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Garbage can theory and Australia's National Electricity Market: Decarbonisation in a hostile policy environment

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ABSTRACT

After two decades of consistent economic and technical performance, conditions in Australia's National Electricity Market (NEM) deteriorated sharply in 2016/17. Prices more than doubled on the east coast, tripled in South Australia (SA), and the SA regional grid collapsed. Nothing spectacular occurred with final demand – this was a supply-side energy crisis driven by the exit of 18% of Australia's coal-fired generation fleet and the inadequate entry of new plant. Australia's NEM encountered an uncoordinated exit-driven episode of the Resource Adequacy problem. In the USA where 18% of coal plant has also exited, Resource Adequacy and low cost energy has been maintained by the entry of an enormous fleet of wind, solar and gas-fired generators. In Australia, an equivalent response did not occur; decades of climate change policy discontinuity meant the speed of coal plant exit was unpredictable, entry of renewables delayed through stop-start policy, and gas-fired plant was subject to critical hold-up due to excess LNG plant investment. Resolution requires a united and stable climate change policy architecture that works with, not against, the NEM's world-class institutional design, and greater transparency around planned plant exit.

1. Introduction

Australia's National Electricity Market (NEM)[2] has been world-renowned for its consistent economic and technical performance under a wide range of market and operating conditions over two decades (Price, 2017; Simshauser, 2014). Yet during 2016/17 NEM conditions deteriorated sharply. Electricity futures for 2018 delivery more than doubled to $89/MWh[3] (cf. long run average spot price of $42.50/MWh[4]) and on 28 September 2016 the South Australian region of the NEM collapsed[5] – Australia's first black system event since 1964. Moreover, the gas market has become unstable and is transmitting structural damage to the NEM through the crucial role that gas-fired generation plays.

To summarise what occurred in the NEM over the preceding decade, during the mid-2000s large reserves of coal seam gas were discovered. From 2008–2013, Australian climate change policies (viz. Carbon Pricing policy and an expanded Renewable Energy Target policy) produced a surge of gas-fired and renewable generation plant investments. This led to a *generalised war of attrition*[6] between incumbent coal plant, low emitting gas-fired generation and renewable plant subsidised by way of 'renewable certificates' in a conventional side-market. Electricity prices began to fall and coal plant slowly began to exit. A change in government in 2013, from social democratic to conservative, led to the cancelation of Carbon Pricing, policy paralysis and policy uncertainty vis-à-vis the Renewable Energy Target. This coincided with excess entry of LNG export terminals, which would eventually have the effect of withdrawing gas from the generation market. The climate change policy vacuum meant the pace of coal plant exit became increasingly unpredictable, and in 2016–2017 with little warning two significant coal plants exited in the South Australian and Victorian regions of the NEM, respectively. Ironically only a few years earlier, academic literature focused on coal plant *barriers to exit* in the NEM rather than the rapid and unpredictable pace of exit (see Nelson et al., 2015;

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[1] Views expressed in this article are those of the author.

[2] The NEM comprises Queensland (QLD), New South Wales (NSW), Victoria (VIC), South Australia (SA), Tasmania and the Australian Capital Territory (ACT). ACT forms part of the NSW region. Western Australia and Northern Territory are too remote.

[3] In Sep17 electricity futures were $95 (NSW), $81 (QLD), $118 (SA) and $107 (VIC) with a NEM weighted average of $89/MWh.

[4] NEM weighted-average spot prices from FY2005-2017, expressed in constant 2017 dollars.

[5] To be clear, this was a security of supply issue rather than a Resource Adequacy issue. However, the changing mix of resources was largely responsible.

[6] A generalised war of attrition involves multiple participants rather than the usual two actors associated with a conventional war of attrition. (See Bulow and Klemperer(1999); Simshauser, (2006).

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Jotzo and Mazouz, 2015). Replacement generation plant entry in crucial segments had been delayed (renewables) or distorted (gas) and thus by 2016/17, record high electricity prices prevailed and could be traced back to three key parameters, viz. 1). two decades of climate change policy discontinuity, 2). a lack of transparency around planned plant exit, and 3). LNG export investment error.

Climate change policy is frequently mobilised through various Carbon Pricing policy mechanisms. This occurs across a wide range of OECD/G20 countries (Nong and Siriwardana, 2017).[7] But at least two countries appear to find this exceedingly difficult to achieve at the national level; the USA (Schelly, 2014) and Australia (Nelson, 2015).[8] To generalise, both countries have social democratic parties that support Carbon Pricing and greater use of renewables, and conservative parties that do not have a unified position, and therefore do not. Both countries have vast fossil fuel reserves that have provided a source of international comparative advantage. Some policymakers argue the introduction of Carbon Pricing and related policy instruments (e.g. Renewable Energy Targets involving taxpayer or consumer-funded subsidies) will damage this advantage (MacGill, 2010; Simshauser, 2011; Byrnes et al., 2013; Jones, 2014; Nelson et al., 2015; Jaraite et al., 2017).

Australia was a signatory to the Kyoto Protocol and to the Paris Agreement with bipartisan political support.[9] Energy utilities and investors anticipate a conventional policy cycle incorporating distinct stages, viz. a rational policy development process guided by a professional public service, a meaningful industry consultation process coupled with the rationality of applied economic problem solving supported by extensive quantitative analysis (given the complexity of power markets) in which to generate sound public policy advice. Advice is prosecuted within the government's agenda and after negotiating within the bounds of reasonable political constraint, relevant policy is legislated and enters into force. For a market-based power system like the NEM to function properly, investor knowledge, expectation and conviction must ultimately match policy settings and policy intent; and vice versa.

But it would be naive for energy industry participants to believe climate change policy development follows a conventional cycle in Australia after two decades of policy discontinuity. Much closer to the mark is *Garbage Can Theory* of policy development, a model extracted by Kingdon (1984) from earlier works by Cohen et al. (1972).[10] As Jones (2014) observes, it provides a helpful interpretation of the operating environment that energy utilities and their investors face in Australia.

At its core, *Garbage Can Theory* rejects the notion that policymaking follows a conventional or methodological process; policymaking is thought to be chaotic, fragmented, random, contingent and frequently "arational" (Tiernan and Burke, 2002). In the model, as policies are developed they frequently fail to make the congested political schedule, and so are dumped in a *garbage can*, thus becoming part of an accumulating set of policy solutions in search of a problem (see Cohen et al., 1972). To be revived, discarded policy solutions require suitable problem definition (Peters, 2002), a political window prised open to create an opportunity for deployment (Howlett et al., 2014; Jones, 2014) and a policy entrepreneur to build acceptance and synchronise all three elements, viz. problem definition, policy solution and the political window of opportunity (Tiernan and Burke, 2002). A *focusing event* is typically required to catalyse *problem definition* and prise open the political window of opportunity (see Kingdon, 1995; Birkland, 1998). Indeed, the essential element of Garbage Can Theory is agenda-setting; for a policy solution to *land* it must make its way to the top of a very congested political schedule spanning health, education, defence, housing and so on; consequently all three conditions, viz. problem definition, policy solution and the political window of opportunity, need to be simultaneously satisfied (Kingdon, 1995; Birkland, 1998; Peters, 2002; Tiernan and Burke, 2002; Howlett et al., 2014; Jones, 2014; Rawat and Morris, 2016).

In the present environment, Australia's energy and climate change policy *garbage can* contained a decade-old policy solution still in search of a problem; a Clean Energy Target mechanism involving tradable certificates below a CO_2 baseline intensity. The collapse of the SA power system, the sudden announcement of Hazelwood power station's closure and the associated doubling of electricity futures prices sparked a *focusing event* and prised-open a political window of opportunity. A *policy entrepreneur* was appointed by the Commonwealth energy minister, viz. Australia's Chief Scientist Dr Alan Finkel. The 'Finkel Review' of the NEM's *focusing event* facilitated *problem definition*, viz. carbon policy discontinuity and the lack of a credible and united post-2020 energy and climate change policy architecture. A problem emerged, however.

The policy was unable to land; the agenda became cluttered with other policy distractions (viz. 50 recommendations in total) and other *policy influentials* (viz. other well-resourced policy entrepreneurs with counter views on climate change policy) were overlooked. Climate change policy is a contested space, and the window was consequently foreclosed by the counter *policy influentials*. In the end, 49 of the 50 Finkel Review recommendations were accepted, and the one that mattered, the Clean Energy Target, was discarded to the *garbage can*.

Two further problems emerged. First, *problem definition* was misspecified. Even if climate policy certainty was delivered tomorrow, it would only partially resolve NEM issues; gyrations in the market for natural gas are in part responsible for the current crisis. Second, the Clean Energy Target, relegated to the *garbage can* in 2007, was the wrong policy solution[11] to the current problem. The Clean Energy Target policy was originally designed to initiate a wave of clean technology investment into a coal-dominated power system, up to 15% market share. As a scheme involving a "side-market" for tradable certificates, it was never intended to be applied after the completion of a 20% Renewable Energy Target (i.e. spanning 20–35% market share).

Certificate schemes like a Clean Energy Target have been demonstrated to work efficiently and effectively in terms of initiating investment (Daly and Edis, 2010). But as certificate schemes or 'side markets' rise in materiality (i.e. greater than 25% market share) they may start to work actively against organised spot electricity markets (see Edenhofer et al., 2013; Helm, 2014; Newbery, 2015; Nelson et al., 2015; Keay, 2016; Pollitt and Anaya, 2016; Neuhoff et al., 2016; Green and Staffell, 2016; Simshauser, 2018). Consequently, a Clean Energy Target following on from a fully subscribed 20% Renewable Energy Target may necessitate the premature re-design of the NEM during an expansionary

[7] Nong and Siriwardana (2017) note this includes EU27 plus Switzerland, Iceland, Norway, New Zealand, South Korea and Kazakhstan. The US states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, Vermont operate a Carbon Pricing schemes. California along with Québec and Ontario have a joint scheme. China launched its ETS at the end of 2017.

[8] Jones (2014) highlights that Canada faces similar issues.

[9] Under the Kyoto Protocol, Australia agreed to limit CO_2 emissions to 108% of 1990 levels, and the Paris Agreement requires CO_2 emissions be limited to 26–28% below 2005 levels by 2030.

[10] The core of Cohen et al. (1972) is that when a decision making environment has become complex, and decision options are problematic, technology is unclear, and participation is fluid, these conditions satisfy a 'garbage can' model of governance.

[11] The intent of the Clean Energy Target was to operate as a technology-neutral extension of Australia's Renewable Energy Target. This intent is very clear; *"…with the additional context that a Clean Energy Target can be implemented within an already well understood and functioning framework, and has better price outcomes, the Panel recommends a Clean Energy Target be adopted…"* (Finkel et al., 2017, p. 97). As Section 2.1 later explains, an unmodified extension of the RET, given known design errors, would almost certainly result in a premature NEM re-design. The Finkel recommendation was issued with a caveat of a 'generator reliability obligation'. Rather than using a market mechanism to deliver minimum dispatchable generation levels, the obligation was to be imposed on individual power projects on a regional basis. See Finkel et al. (2017, Chapter 4).

investment phase. This would seem to be a predictable outcome unless the Clean Energy Target policy was adopted in name then *heavily modified* in application.

The purpose of this article is to review the build-up of Australia's climate change policy *garbage can*, further refine the *problem definition*, and draw out key lessons from the NEM's recent experience. This article is structured as follows. Section 2 reviews Australian climate change policy literature. Section 3 reviews the consequences of climate change policy discontinuity by contrasting generation plant entry and exit in Australia and the USA. Section 4 produces the evolution of generalised entry costs for new plant along with a comparison to incumbent plant over the 2007–2017 period, and demonstrates why *re-investment* is a term that will progressively gain traction in mid-term policymaking. Section 5 reviews the gas market. Conclusion and policy implications follow.

2. Review of Australian literature: the climate change policy *garbage can*

Australia's NEM has a two-decade history of climate change policy discontinuity (Byrnes et al., 2013; Molyneaux et al., 2013; Nelson et al., 2013; Byrnes et al., 2013; Freebairn, 2014; Garnaut, 2014; Wagner et al.al., 2014; Nelson, 2015; Apergis and Lau, 2015). Australia's climate change policymaking cycle can be traced at least as far back as 1997 when Australia signed the Kyoto Protocol (Jones, 2009; Nelson et al., 2010). Policy advice focused on a Renewable Energy Target and an Emissions Trading Scheme (Jones, 2010).[12]

2.1. Renewable Energy Target

Australia introduced the world's first renewable energy portfolio standard after initiating policy development in 1997, passing legislation in 2000 and commencing the scheme in 2001 (MacGill, 2010; Buckman and Diesendorf, 2010; Jones, 2010). The Renewable Energy Target or RET mandated an additional 2% of energy be produced from renewable sources (Forrest and MacGill, 2013; Byrnes et al., 2013; Cludius et al., 2014). RET liability was placed on electricity retailers and mobilised by "tradeable certificates" with a non-compliance penalty of $40/MWh (Jones, 2009; Nelson et al., 2013).

A review of the 2% RET in 2003 (Tambling Review[13]) found the 2% target would be met four years ahead of schedule in 2006 (Buckman and Diesendorf, 2010; Daly and Edis, 2010). The Tambling Review recommended extending and expanding the RET but was rejected by the incumbent conservative commonwealth government (Jones, 2009). Inaction by the commonwealth led to Victoria legislating its own 10% target, with NSW and SA preparing to follow suit (Nelson et al., 2013; Jones, 2014; Cludius et al., 2014). Queensland legislated a 15% Clean Energy Target with 'technology set-asides' (Schelly, 2014) comprising a 13% Gas Electricity Certificate scheme and a 2% renewable target (MacGill et al., 2006; Nelson et al., 2010).

In response, the 2007 Commonwealth election elicited two election commitments from the major parties; the incumbent conservative government committed to a national 15% Clean Energy Target and the social democratic opposition committed to a greatly expanded 20% RET by 2020 (Jones, 2010; Nelson et al., 2013; Apergis and Lau, 2015). Following the election, the incoming social democrats legislated the 20% RET in 2009[14] while the 15% Clean Energy Target was discarded (Cludius et al., 2014).

The 2% RET and its associated side market (i.e. certificate market) had trivial impacts on Australia's organised spot markets but expanding the scheme to 20% without adjustment revealed a number of material design flaws. The policy lacked in-built mechanisms to reduce incentives over time (Buckman and Diesendorf, 2010). 'Energy Intensive Trade Exposed' (EITE) industries were treated differentially and were largely excluded from RET cost recovery[15] - instead RET costs were shifted to residential households and in consequence transient merit-order effects benefited EITE customers disproportionately (see Jones, 2010; Forrest and MacGill, 2013; Byrnes et al., 2013; Cludius et al., 2014; Bell et al., 2015). Furthermore, little thought went into the interplay between renewable certificate prices and negative spot prices[16] or the provision of Frequency Control Ancillary Services and consequently even now no VRE generator in Australia provides system stability services (MacGill, 2010; Bunn and Yusupov, 2015). Compounding matters, two-yearly reviews of the 20% RET, ironically negotiated by the Greens, produced a stop-start investment cycle centred around the timing of legislated biannual policy reviews. But perhaps the most destructive design error was absence of technology set-asides for small-scale solar PV; instead they were included with output "deemed" and "multiplied".

The nominal output of small-scale solar PV was "deemed" for 15 years in advance and certified in the year of installation (to reduce transaction costs). This enabled 15 years of certificates to be created in year 1. Furthermore, a Rooftop Solar Multiplier of 5 × was added to accelerate technology adoption. The combination of "deeming" and the "Multiplier" meant 75-years of Renewable Energy Certificates were created in the year a rooftop solar PV unit was installed (i.e. 5 × Multiplier, 15 years deemed output). The certificates, colloquially referred to as "Phantom RECs" in the literature, flooded the market and destabilised the RET policy (see Buckman and Diesendorf, 2010; Nelson et.al. 2012; Cludius et al., 2014). Phantom RECs resulted in the renewable scheme being annexed into small and large scale RET policies in June 2010 (Nelson et al., 2013; Byrnes et al., 2013; Cludius et al., 2014; Nelson, 2015).

Following the 2013 election, the new conservative government initiated another review of the RET ('Warburton Review'). With electricity demand contracting for the first time in 121 years, the 20% RET – which was initially expressed as a fixed 45000 GWh target but reduced to 41000 GWh following the Phantom REC annexure of small-scale renewables – was looking more like a 25–30% Target (Nelson et al., 2013; Byrnes et al., 2013). The Warburton Review focused on the policy effects, viz. forcing more intermittent capacity into an increasingly oversupplied and unstable wholesale electricity market while associated REC certificate costs were levied on consumers (at the retail level). This was occurring at a time when residential electricity tariffs and network charges in particular were rising sharply (Simshauser et al., 2011; Cludius et al., 2014; Garnaut, 2014; Nelson et al., 2015; Bell et al., 2017). The RET was once again fundamentally altered – scaled back from 41000 GWh to 33000 GWh in mid-2015 (Biggs, 2016).

[12] The Howard Government released a broad climate policy strategy titled "Safeguarding the Future: Australia's Response to Climate Change. On 20 November 1997 Prime Minister Howard announced that the Commonwealth would work with the State Governments to "set a mandatory target for electricity retailers to source an additional two per cent of their electricity from renewable energy sources by 2010". In the same speech, the PM stated on emissions trading that "Australia also believes that an international emissions trading regime would help minimise costs of reducing emissions. We would support emissions trading on the basis of a satisfactory initial allocation of emission entitlements and a practical resolution of the administrative difficulties involved." (see Parliament of Australia at: http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query%3DId%3A%22chamber%2Fhansardr%2F1997-11–20%2F0016%22 – accessed August 2017).

[13] See Tambling Review at http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query=Id%3A%22library%2Flcatalog%2F00122747%22.

[14] The legislation was the Renewable Energy (Electricity) Amendment Act 2009. Around the same time, the Renewable Energy Directive (mandating the EU15 achieve 20% renewable energy production by 2020) also entered into force (see Jaraite et al., 2017).

[15] Energy intensive customers from mining and manufacturing were shielded from the cost of the RET with 90% and 60% exemptions. (See Byrnes et al. (2013) or Buckman and Diesendorf (2010)).

[16] Bunn and Yusupov (2015) note negative prices occur in Australia, North America, Germany, Denmark and Spain.

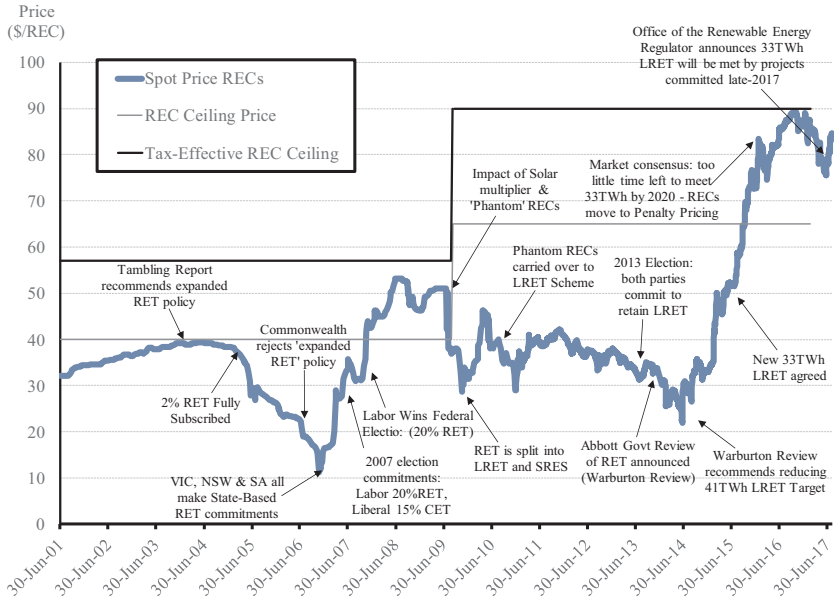

Fig. 1. REC Spot Prices (2001–2017).
Nelson et al. (2013), BNEF.

As Fig. 1 illustrates, policy decisions and political events were frequent drivers of non-trivial REC price changes (see also Buckman and Diesendorf, 2010; Nelson et al., 2013; Cludius et al., 2014; Nelson, 2015; Nelson et al., 2015).

2.2. Carbon Pricing

As with the RET, Carbon Pricing policy development also commenced from 1997 (Jones, 2010). A Cap and Trade Emissions Trading Scheme (ETS) design emerged in the early 2000s following a conventional policymaking cycle orchestrated by the then Australian Greenhouse Office (see AGO, 1999a, b; Nelson et al., 2010). Evidently however, Cabinet Ministers involved in sponsoring the ETS policy had misjudged the then Prime Minister's appetite for internalising CO_2 emissions due to perceived adverse effects on Australia's low cost energy; consequently the policy was discarded before legislative drafting commenced (Simshauser and Tiernan, 2018). With Australia's international greenhouse gas commitment known, and no matching policy framework, sub-national State Governments filled the policy vacuum in Australia – just as occurred in the US and Canada (Schelly, 2014; Jones, 2014).[17] In 2003, NSW introduced the world's first CO_2 ETS[18] and as noted in Section 2.1 Queensland implemented its 15% Clean Energy Target with gas and renewable set-asides (MacGill et al., 2006; Jones, 2009; Nelson et al., 2010). Both schemes were highly successful in that they met their objectives faster and at lower cost than any market forecast at the time (Daly and Edis, 2010). Given the success of the NSW and Queensland schemes, inaction by the Commonwealth, and underpinned by the fact that all sub-national governments had migrated to social democratic leaders, in 2006 Australia's state governments agreed to a "State-based National ETS" (see NETT, 2006; Jones, 2014). As Nelson et al. (2010) explain, with every state committed the so-called NETT policy was credible and taken seriously by industry.

The 2007 commonwealth election produced two election commitments in response; the incumbent conservative government was forced to adopt an ETS policy and the opposition social democratic party, informed by the work of state counterparts, also adopted an ETS policy (Jones, 2010; Nelson et al., 2010). Thus after 10-years of uncertainty a central tenet of climate change policy was finally bi-partisan (Garnaut, 2014).

Following the 2007 national election, the new social democratic government progressed legislation for an ETS (Buckman and Diesendorf, 2010; Jones, 2010). NSW and Queensland closed down their respective state-base schemes to remove the risk of policy duplication (Nelson, 2015). However, a change in conservative party leadership in late-2009 grounded in an anti-ETS narrative meant the political environment surrounding an ETS became so toxic that the social democratic government pulled the ETS policy from their legislative agenda and announced it would be delayed until at least 2013 (Nelson, 2010; Jones, 2014).

A minority social democratic government emerged from the 2010 national election and revived the ETS policy with legislation passed in 2011 (Garnaut, 2014). The scheme commenced from 1 July 2012 with a A$23/t carbon price, fixed for three years before transitioning to a conventional cap and trade ETS (Wild et al., 2015). Although the fiscal effects were minimal due to windfall tax recycling, the scheme was poorly designed and recycling poorly targeted (Freebairn, 2014; Robson, 2014). Compounding matters were the timing of the $23/t

[17] Jones (2014) highlights there is no national scheme in Canada, but Ontario (and Quebec) operate sub-national schemes. Schelly (2014) explains there is no national climate policy in the US per se and consequently States have taken a leadership role; more than half of the US state have a Renewable Portfolio Standard although ironically, no two schemes are alike. Peters and Hertel (2017) note that in August 2015 the US Environmental Protection Agency announced the Clean Power Plan to reduce CO2 emissions by 32% below 2005 levels by 2030 – but they also note Business As Usual is likely to achieve this target.

[18] As Daly and Edis (2010) note, the US initiated the first Cap and Trade schemes in the market for SO_x. The NSW 'Baseline and Credit' mechanism was organised with electricity retailers being the liable party and subjected to a gradually declining 'CO_2 per capita' target. Although a NSW scheme, it was open beyond the borders of NSW and extended to any facility connected to the National Electricity Market. More than 130 CO_2-emitting facilities qualified and abatement of 73 mt was achieved prior to scheme closure in 2010. See Nelson et al. (2010) for further details.

fixed price; these made the ETS scheme politically vulnerable because simultaneously EU permits had crashed from €30/t a few years earlier to just €6/t or A$8.60/t (Simshauser and Tiernan, 2018). The ETS thus became central to the 2013 national election. The incoming conservative government dismantled and discarded the ETS policy for a third time, albeit following two years of operational experience.

The new conservative government replaced the ETS with a Direct Action Plan, a taxpayer funded reverse auction scheme designed to centrally purchase CO_2 abatement (Apergis and Lau, 2015) Nong and Siriwardana (2017) and Freebairn (2014) explain the benefits and limitations of the policy, but above all its fiscal durability was questionable when in 2015 Australia signed a new (and bipartisan) international agreement to reduce emissions by 26–28% below 2005 levels by 2030 at the Paris Conference of the Parties. The Commonwealth Government subsequently committed to a climate change policy review, to be completed during 2017 with the 2030 emissions target in mind.

In the period leading up to the commonwealth's 2017 climate change policy review, state governments, generators, energy retailers, industry groups and energy consumer groups progressively formed a unified position around an Emissions Intensity Scheme (EIS). The "contracting, uniform baseline & credit" ETS policy was becoming increasingly important because coal plant began to exit and gas-fired plant was being withdrawn (Forrest and MacGill, 2013; Bell et al., 2015, 2017; Apergis and Lau, 2015). But within hours of announcing the climate change policy inquiry and the prospect of an EIS as the policy mechanism, a conservative party backbench revolt led to direct intervention by the Prime Minister, and the EIS policy option was killed-off and discarded before the review had even started (Simshauser and Tiernan, 2018).

Following the collapse of the SA power system the Commonwealth government initiated a review of the NEM to be led by the Chief Scientist, Dr Alan Finkel. The Finkel Review, noting the EIS had been discarded, proceeded by reaching into the *garbage can* and recovering a 2007 policy option – a Clean Energy Target. Yet within weeks of being announced, commonwealth government support for the "CET" policy alternative began to unwind and by October 2017 had been discarded.

At the time of writing, work continues on the development of a policy comprising an Emissions Mechanism and a Reliability Mechanism. But policy support remains uncertain and consequently, a policy vacuum will exist in both strands of climate policy, Carbon Pricing & Renewable Energy Targets after 2020. If nothing else, Australia's climate change policy *garbage can* is full, with many practical experiments along the way.

3. Nature of the problem: plant exit and plant entry

Australia and the USA are both characterised by vast coal, gas and renewable resources, acute differences in State and Federal positions on climate change policy, and as Byrnes et al. (2013) and Schelly (2014) note respectively, a lack of a united energy and climate change policy structure at the national level. But in the US, climate change policies of subnational governments and their Renewable Portfolio Standards in particular have been durable, whereas in Australia, national and state-based climate change policies are best described as discontinuous, as Section 2 explained. The effects of this becomes evident from the entry statistics in Tables 1–5.

Table 1
US Generation Fleet in Service (1930–2017).
Source: US EIA

Year of Operating duty	Coal plant		Gas plant		Non-hydro renewables		Total plant	
	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)
1930–1939	4	10,579	5	29	3	19	1658	41,922
1940–1949	19	14,483	36	774	14	159	478	42,911
1950–1959	147	35,130	201	15,131	49	671	1172	77,404
1960–1969	172	48,078	299	33,526	50	1311	1551	120,629
1970–1979	230	65,707	573	59,916	33	930	1794	203,037
1980–1989	165	47,035	375	15,144	186	3863	2101	123,117
1990–1999	67	21,087	731	53,009	125	3327	2241	104,916
2000–2009	25	34,750	2056	270,109	704	33,948	5043	335,882
2010–2017	26	9873	471	63,919	3001	73,004	4884	133,462
Total	855	286,721	8328	511,558	4843	117,231	20922	1,183,280
Average Age		39 Yrs		21 Yrs		8 Yrs		29 Yrs

Table 2
US Coal Plant Exit vs Gas & Renewable Entry.
Source: US EIA

Year of Exit/entry	Coal retirements		Gas plant entry			Renewable entry	
	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)	CCGT component (MW)	Number of plant	Installed capacity (MW)
2005–2012	245	11,257	648	81,775	72,925	1500	57,449
2013–2017	384	50,367	241	36,183	14,490	2042	44,998
Total	629	61,624	889	117,958	87,416	3542	102,447
Average Age		52 Yrs					
Coal Fleet Closure (%)		18%					

Table 1 outlines the existing US generation fleet and catalogues plant entry commitments by decade (from 1930- through to 2010-). Coal, gas and non-hyrdo renewable plant are separately identified. Note that Total Plant incorporates these technologies along with other plants such as hydroelectric, nuclear, oil-fired and so on. Note the total fleet is 1183,280 MW with an average age of 29 years, including 855 coal plants totalling 286,721 MW with a fleet average age of 39 years.

Table 2 isolates Coal Retirements (i.e. exit) from 2005 to 2017, and contrasts this with Gas Plant Entry and Renewable Entry. Note that 629 coal plants have exited totalling 61,624 MW, representing 18% of the US coal-fleet. At exit, the average age of plant was 52 years. Coal plant exit follows sharp declines in gas prices, the introduction of mercury standards, resource constraints, 30% capital (tax-credit) subsidies for solar and wind, and stable Renewable Portfolio Standards in more than half of the US states (Schelly, 2014; Peters and Hertel, 2017).

From an entry perspective, 889 gas generators totalling 117,958 MW have replaced coal plant exits and importantly, 87,416 MW of this is base/semi-base Combined Cycle Gas Turbine (CCGT) plant. Furthermore, 3542 renewable projects totalling 102,447 MW have been commissioned.

Table 3 provides an equivalent overview of plant in service in Australia. Australia has 24,436 MW of coal plant with an average age of 30 years, and total installed capacity of 62,578 MW with a fleet average age of 26 years.

Table 4 outlines coal exit while Table 5 outlines exit and non-coal entry statistics. As Table 5 illustrates. Australian coal plant exit results are strikingly similar to the US on a proportional basis. Where a stark difference exists is Gas Plant Entry and Renewables Entry.

Table 3
Australian Generation Fleet in Service (1930–2017).
Source: ESAA, BNEF

Year of Operating duty	Coal plant		Gas plant		Non-hydro renewables		Total plant	
	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)
1930–1939	0	0	0	0	1	28	4	105
1940–1949	0	0	1	60	1	29	3	117
1950–1959	0	0	0	0	6	139	15	1302
1960–1969	0	0	1	480	9	157	25	5530
1970–1979	3	5025	4	1377	21	256	35	9928
1980–1989	4	11,780	7	1687	6	86	51	15,539
1990–1999	3	4226	26	2806	58	404	59	7666
2000–2009	6	3197	38	9212	125	2139	178	16,147
2010–2017	1	208	14	3075	79	3271	142	6244
Total	17	24,436	91	18,697	306	6511	512	62,578
Average Age		30 Yrs		17 Yrs		12 Yrs		26 Yrs

Table 4
NEM Coal Plant Exit.
Source: AEC

NEM region	MW	Exit	Start	Age (Yrs)
QLD	500	2012	1972	40
SA	240	2012	1960	52
QLD	180	2013	1972	41
NSW	600	2013	1969	44
VIC	195	2014	1958	56
NSW	1000	2014	1978	36
NSW	151	2015	2001	14
VIC	150	2016	1969	47
SA	540	2016	1985	31
VIC	1600	2017	1967	50
Total	5156			42

Table 5
Australian Coal Plant Exit vs Gas & Renewable Entry.
Source: ESAA, BNEF

Year of	Coal retirements		Gas plant entry			Renewables entry	
Exit/entry	Number of plant	Installed capacity (MW)	Number of plant	Installed capacity (MW)	CCGT component (MW)*	Number of plant	Installed capacity (MW)
2005–2012	2	740	31	8674	2546	112	2640
2013–2017	9	4656	4	218	52	49	2422
Total	11	5396	35	8892	2598	161	5062
Average Age		42 Yrs			*Swanbank E mothballed in 2015		
Coal Fleet Closure (%)		18%					

Table 6 and Fig. 2 provide comparative statistics between the two countries – with Table 6 outlining the entry/exit ratios and Fig. 2 contrasting generation output in 2006 and 2016. The first point to note is that Coal Fleet Exit is 18% in both countries. The major difference lies in plant entry; Australian semi-base CCGT Plant Entry is third the US result (1.4 × vs 0.5 ×) and Renewable Plant Entry is a half of the US result (1.7 × vs 0.9 ×). Both CCGT plant and Renewables have an energy-production bais (as distinct from Open Cycle Gas Turbines, which have a peak capacity bias). US statistics do not represent an "optimal target" per se, but comparative analysis provides clues as to why energy prices in the NEM have risen as coal plant has exited, and why US prices remain low and stable in spite of an equivalent episode of coal plant exit.

Table 6
US and Australian entry/exit ratios.
Source: US EIA, ESAA, BNEF

	Coal fleet exit	Average exit age	Gas plant entry ratio	CCGT component	Renewables plant entry ratio
USA	18%	52 Yrs	1.9 × Coal Exit	1.4 × Coal Exit	1.7 × Coal Exit
Australia	18%	42 Yrs	1.6 × Coal Exit	0.5 × Coal Exit	0.9.x Coal Exit

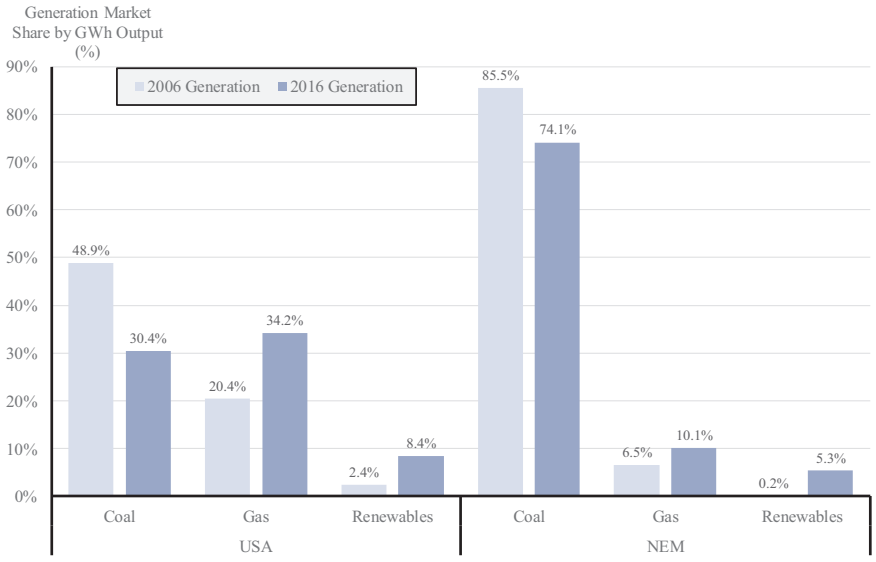

Fig. 2. US and Australian coal, gas and renewable generation market shares (2006 & 2016).
ESAA, AEC, EIA.

The difference in Renewables entry is explained by the policy discontinuity; in Australia the commonwealth government has reviewed the RET on six separate occasions and fundamentally altered the policy three times whereas in the US, state-based Renewable Portfolio Standards have been comparatively stable. The differential in gas-fired plant entry (Table 6) and gas-fired generation market share (Fig. 2) is explained in Sections 4 and 5.

4. The generalised cost of plant entry

In order to analyse entry dynamics and relevant policy settings, it is helpful to identify generalised long run marginal costs of the NEM's entrants. The *PF Model,* a dynamic multi-period post-tax discounted cash flow model, has been designed specifically for this purpose. It solves for multiple generating technologies, business combinations and financing structures and simultaneously determines convergent price, debt-sizing and post-tax equity returns, K_e. Outputs are similar to levelised cost estimates but with a level of detail well beyond conventional Levelised Cost of Electricity Model estimates because corporate and project financing constraints and taxation variables are co-optimised. The model logic appears in Appendix I with key data inputs presented in Tables 7–8 for five new entrant technologies over three time-horizons with two financing structures:

Tables 7–8 provide sufficient data to produce generalised long run marginal cost estimates across three specific timeframes, 2007, 2012 and 2017. These dates were selected because they capture three distinct phases of generator entry costs which in turn help to explain NEM entry dynamics in the presence of policy uncertainty – both historically, and in the short- to mid-term. In 2007, fuel costs and capital costs for thermal plant were at their low point. 2012 follows the Global Financial Crisis which impacted the cost of capital, and Australia's second resources boom, which profoundly impacted construction costs and therefore the installed capital cost of generating equipment. 2012 entry costs also capture early-stage fuel cost increases. The 2017 entry costs follow the sharp plunge in the capital cost and cost of capital for renewable plant, ongoing capital cost increases for thermal plant, and final stage gas price increases.

Table 7
Technology Assumptions 2007–2017.

Technology	Capex ($/kW)	Installed capacity (MW)	Generating units (MW)	Unit heat rate (kJ/kWh)	Thermal efficiency (%)	Unit fuel cost ($/GJ)	Capacity factor (%)	Fixed O&M cost ($/MW/a)	Variable O &M ($/MWh)	Capital works (%)	Auxiliary load (%)	Carbon intensity (t/MWh)
2007 Inputs												
Black Coal	1500	1000	2	9500	37.9	1.00	90%	48,000	1.00	0.25%	7.00%	0.87
Brown Coal	2250	1000	2	12,150	29.6	0.40	90%	55,000	1.30	0.25%	8.00%	1.10
CCGT	1200	380	1	7000	51.4	3.25	85%	10,000	3.00	0.05%	2.00%	0.36
Wind	2100	200	100	–		–	37%	40,000	1.00	0.05%	2.00%	–
Solar PV	4000	20	–	–		–	24%	62,000	–	0.05%	0.50%	–
2012 Inputs												
Black Coal	2250	1000	2	9000	40.0	1.25	90%	49,250	2.00	0.25%	7.10%	0.82
Brown Coal	3000	1000	2	11,613	31.0	0.40	90%	60,250	4.00	0.25%	9.60%	1.05
CCGT	1250	380	1	6965	51.7	5.50	85%	10,000	7.00	0.05%	3.00%	0.36
Wind	2500	450	180	–		–	39%	45,000	1.00	0.05%	2.00%	–
Solar PV	3500	100	–	–		–	28%	59,435		0.05%	0.50%	–
2017 Inputs												
Black Coal	3050	1000	2	8450	42.6	1.54	90%	50,500	4.00	0.25%	7.10%	0.77
Brown Coal	4000	1000	2	11,150	32.3	0.40	90%	65,500	5.00	0.25%	9.60%	1.01
CCGT	1500	380	1	6930	51.9	8.00	85%	10,000	7.00	0.05%	3.00%	0.36
Wind	1787	450	118	–		–	41%	50,000	1.00	0.05%	2.00%	–
Solar PV	1500	100	–	–		–	30%	56,870	–	0.05%	1.00%	–

Table 8
Corporate Finance Assumptions.

Wind & solar		2007	2012	2017	Coal & gas		2007	2012	2017
Debt Sizing Constraints					Debt Sizing Constraints				
- DSCR	(times)	1.35	1.35	1.35	- FFO/I	(times)	5	5	5
- LLCR	(times)	1.35	1.35	1.35	- FFO/D	(times)	3	3	3
- Gearing Limit	(%)	85.0	85.0	65.0	- Gearing Limit	(%)	35.0	35.0	35.0
- Default	(times)	1.10	1.10	1.10					
Project Finance Facilities - Tenor					Corporate 'BBB' Bond Issue				
- Tranche 1 (Bullet)	(Yrs)	5	5	5	- Tranche 1 (Bullet)	(Yrs)	5	5	5
- Tranche 1 Refi	(Yrs)	13–20	13–20	13–20	- Tranche 1 Refi	(Yrs)	13–20	13–20	13–20
- Tranche 2 (Amort.)	(Yrs)	12	12	7	- Tranche 2 (Amort.)	(Yrs)	12	12	7
- Tranche 2 Refi	(Yrs)	6–13	6–13	6–13	- Tranche 2 Refi	(Yrs)	6–13	6–13	6–13
- Notional amortisation	(Yrs)	18–25	18–25	18–25	- Notional amortisation	(Yrs)	18–25	18–25	18–25
Project Finance Facilities - Pricing					BBB' Bond Pricing				
- Tranche 1 Swap	(%)	6.14	3.69	2.45	- Tranche 1	(%)	6.69	6.26	3.74
- Tranche 1 Margin	(bps)	120	250	200	- Tranche 1 Margin	(bps)	54	257	129
- Tranche 2 Swap	(%)	6.10	3.98	2.66	- Tranche 2	(%)	6.78	6.55	4.15
- Tranche 2 Margin	(bps)	140	275	220	- Tranche 2 Margin	(bps)	69	257	149
- Tranche 1	(%)	7.34	6.19	4.45	- Tranche 1	(%)	6.69	6.26	3.74
- Tranche 2	(%)	7.50	6.73	4.86	- Tranche 2	(%)	6.78	6.55	4.15
- Tranche 1&2 Refi	(%)	7.50	6.73	4.86	- Tranche 1&2 Refi	(%)	6.78	6.55	4.15
- Post Tax Equity	(%)	15.0	12.0	8.5	- Post Tax Equity	(%)	12.0	12.0	12.0

Fig. 3 presents 2007 entry costs for the new entrant technology set including brown and black coal, CCGT, wind, solar and OCGT. These results are contrast with an incumbent (sunk and semi-depreciated) black coal plant at $37.75/MWh, which is slightly below the cost of a new entrant coal plant at $39.79/MWh followed by semi-base Combined Cycle Gas Turbine (CCGT) plant at $45.99/MWh.

Entry costs for Wind, an intermittent resource, was $81 while solar PV was well above $200/MWh at the time. For completeness, a peaking OCGT is included at its carrying cost of $11/MWh and marginal running cost of $43/MWh, reflecting low cost gas. Notice along the x-axis that renewable plant have 73% debt in their capital structures; these are assumed to be Project Financed whereas all other plant are conventional balance sheet or corporate financings with investment grade credit metrics (30–34% gearing).

Fig. 4 presents 2012 results. Notice the distinct gap emerging between semi-depreciated incumbent coal plant, new entrant coal, and new gas plant – the former due to sharply rising capital costs and the latter due to rising fuel costs. However, while capital costs of all new entrants increased materially (viz. 20–50%), for VRE plant this was largely offset by their falling cost of capital.

Fig. 5 presents 2017 results. The gap between incumbent and new entrant coal is now very material while reductions in entry costs for wind and solar are striking, reflecting international trends in renewables (see Jaraite et al., 2017; Wiser and Bolinger, 2017). By comparison to 2012, there are three key changes; (1) the cost of capital has fallen further, especially for project financed renewables; (2) the capital cost of thermal plant has risen by 30% whereas the capital cost of renewable plant has fallen by 30%, and the relative output of wind has

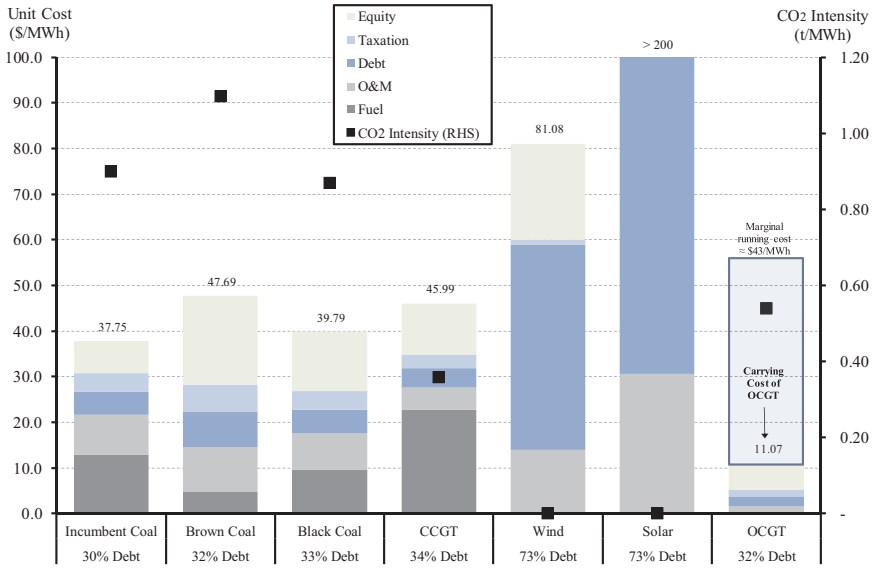

Fig. 3. 2007 generalised entry costs.

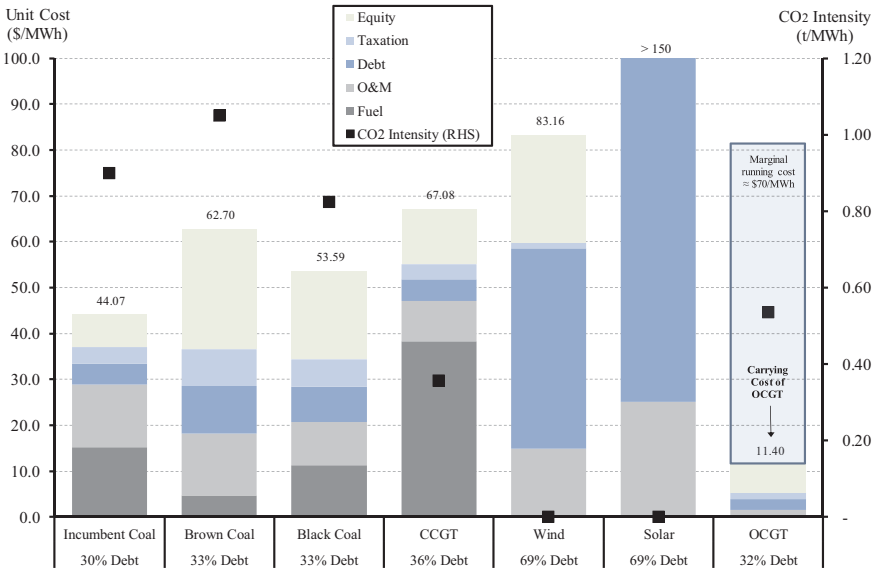

Fig. 4. 2012 generalised entry costs.

increased materially (from mid-30 s to 40% + ACF) as Wiser and Bolinger (2017) observe; and (3) the cost of fuels and gas in particular continues to escalate. This evolution of generator entry cost dynamics has been captured in Fig. 6.

Figs. 3–6 need to be interpreted carefully. First, there is no real-world observation for coal and gas-fired generation in 2017 – the numbers are engineering estimates whereas VRE results can be observed from the many projects currently under construction. Second, VRE plant are intermittent – cost estimates do not take into account the value of output and as such provide apples and oranges comparison.[19] Nonetheless, in an environment that is short energy and long capacity, project financed renewables are emerging as the lowest cost entrants even in the absence of a price on carbon. The caveat is that adequate *flexible capacity* exists – something which remains an unresolved issue for the SA region of the NEM.

5. Gas policy, investment failure & problem mis-specification

The most under-analysed aspect of the NEM, in my opinion, has been the market for natural gas in spite of the structural damage it is transmitting to the electricity market. The purpose of the Finkel Review was to provide a policy blueprint to guide "NEM adjustment" given higher levels of VRE plant, and the exit of coal plant following the SA system collapse *focusing event*. Unfortunately problem definition by the Review was partial. As Section 3 (Table 6 and Fig. 2 in particular) highlighted, exit was not matched by adequate entry and most problematic by comparison to prior episodes of high spot prices was the relative failure of gas-fired plant entry in response to rising prices. This is illustrated in Fig. 7 which contrasts the entry of gas-fired plant with NEM spot prices (note plant entry has been shifted forward by 2 years to account for a

[19] Levlised Cost of Energy (LCoE) is flawed because it treats technology output as homogeneous (see MacGill, 2010; Joskow, 2011; Mills and Wiser, 2012; Hirth, 2013; Edenhofer et al., 2013; Hirth et al., 2016; Simshauser, 2018).

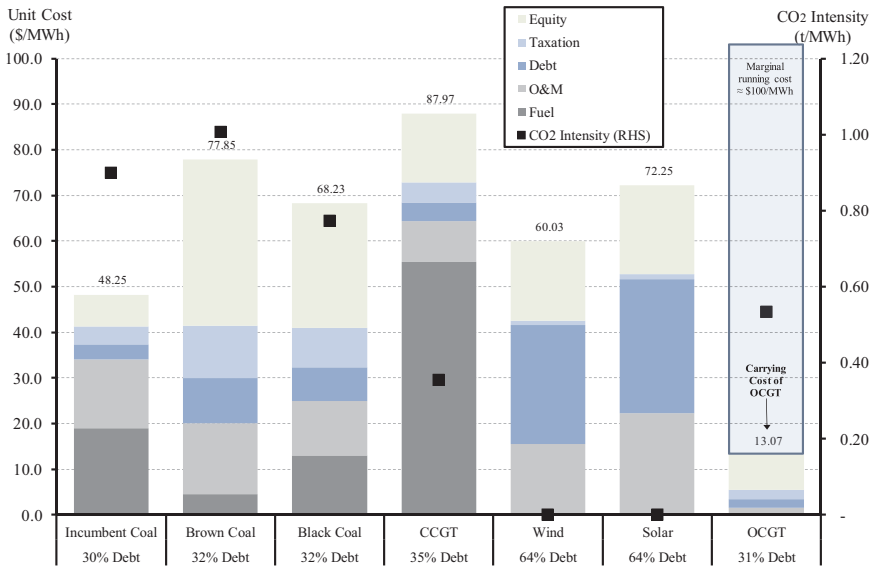

Fig. 5. 2017 generalised entry costs.

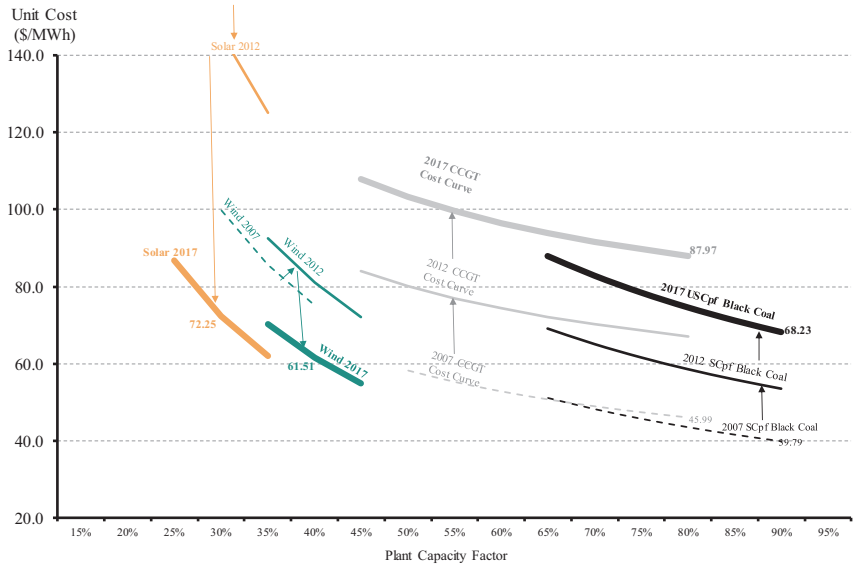

Fig. 6. Evolution of entry costs 2007–2017.

nominal construction lags).[20] This apparent failure has been driven by an enduring episode of scarcity pricing in the gas market, and consequently the increase in the entry cost of gas-fired plant as depicted in Figs. 3–6.

In the 1990s the NEM's supply-side was dominated by incumbent coal-fired generation plant. New entry was also dominated by coal plant through to 2004 with four new Supercritical coal-fired plant committed in Queensland. However, from 2003 to 2010 gas-fired generation increasingly became the entrant technology of choice with a noticeable increase occurring in response to elevated wholesale electricity prices in 2007–2008 as Fig. 7 illustrates. But gas-fired power station commitments ceased from 2010 because conditions in the gas market fundamentally changed (Molyneaux et al., 2013; Wagner et al.al., 2014). Indeed, not only did gas-fired plant fail to enter, CCGT plant was being withdrawn in 2015 (see Fig. 7).

Historically, gas prices in Australia had a long-dated trading range of $3.00-$4.00/GJ. Large discoveries of Coal Seam Gas, well beyond what domestic markets could readily consume, led to various consortiums pursuing development of LNG export terminals. Five proponents (three credible) emerged with projects comprising 2 × 250 PJ/a capacity. Given existing domestic demand of 680PJ/a, this would have two primary effects. First, a threefold increase in gas demand via LNG exports would drive prices to the marginal cost of extraction, nominally $5-$7/GJ, reflecting the higher underlying cost structure of marginal gas resources deployed. Second, it would link the domestic market to the export market and its associated higher prices (nominally $6-$9/GJ long-run netback price). Table 9 outlines details of the three LNG projects that proceeded (*notionally* led by Shell,[21] Origin Energy & Santos) and includes commitment date, export quantities,

[20] Finkel et al. (2017, p. 102) suggest 4900 MW of proposed new gas-fired generation capacity has been publicly announced, based on AEMO data. However, a detailed perusal of the AEMO project data reveals (1) not a single gas-fired project has a target commissioning data, (i.e. they are all "TBA") and (2) the majority are in fact pre-2011 gas-fired projects that failed to get developed during the last price cycle. AEMO data by region is available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[21] The original project lead was BG Group following its acquisition of Queensland Gas Company. Shell announced its plans to acquire BG Group in November 2015 and was completed in February 2016.

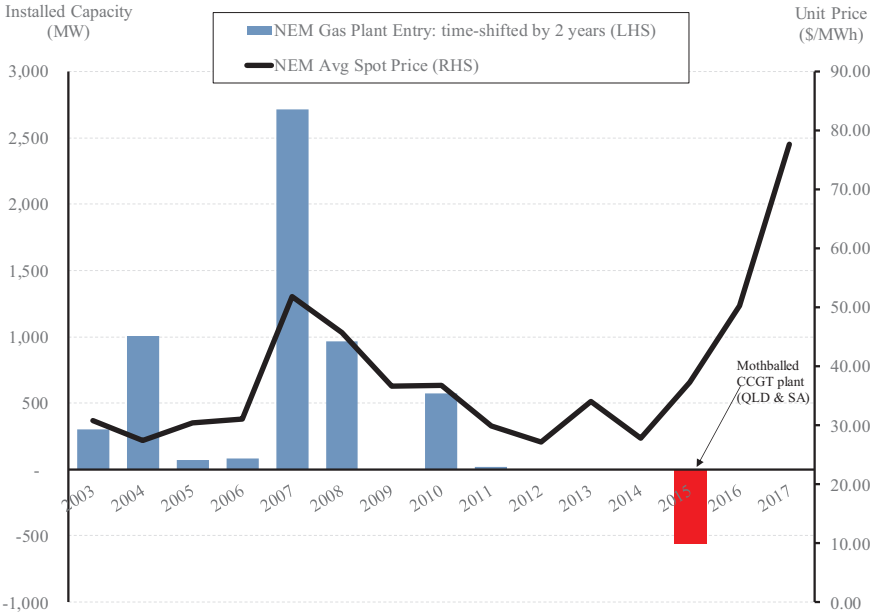

Fig. 7. NEM gas plant entry and average spot prices.
ESAA, AEMO.

Table 9
Australian East Coast LNG projects.
Source: AGL Energy, EnergyEdge

LNG project	Domestic proponent	Project commitment date	Nameplate capacity (PJ/a)	Maximum capacity (PJ/a)	Contracted supply (PJ/a)	Comissioning date Train 1	Comissioning date Train 2
QCLNG	Shell	30-Oct-10	504	549	474	28-Dec-14	5-Jul-15
APLNG	Origin Energy	04-Jul-12[a]	534	575	510	2-Jan-16	6-Oct-16
GLNG	Santos	13-Jan-11	463	498	427	27-Sep-15	25-May-16
TOTAL			1500	1622	1411		

[a] APLNG Train 1 was committed on 28 July 2011.

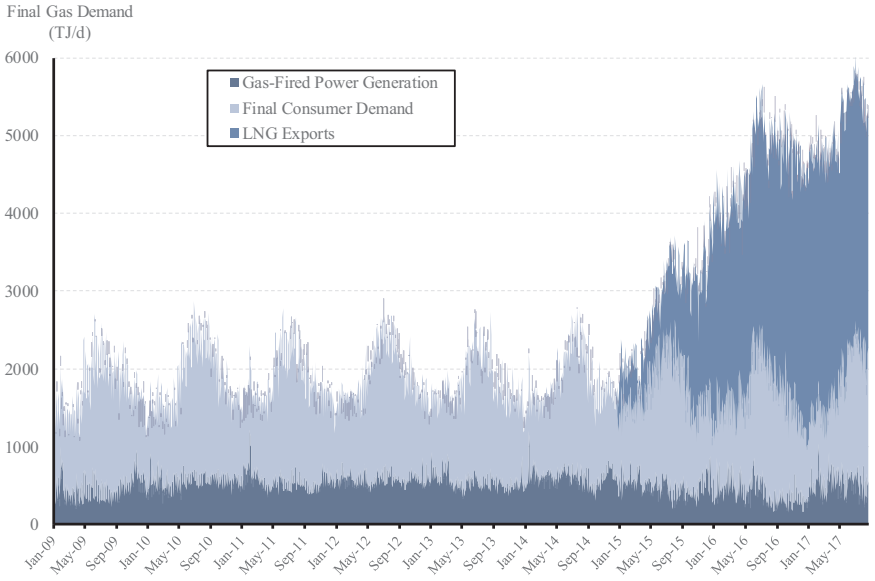

Fig. 8. Gas production.
EnergyEdge GMAT.

and commissioning dates.

As Fig. 8 illustrates, development of three LNG terminals resulted in final gas demand increasing from 680PJ/a to 2000PJ/a in a period of just three years – noting that the first 680PJ/a was developed over a 50 year period (Simshauser and Nelson, 2015a).

projects were independently committed (Simshauser and Nelson, 2015b). As Garnaut (2014, p. 499) later observed *'benefits of gas production would be diminished by private investors' economically excessive investment in export capacity'*.

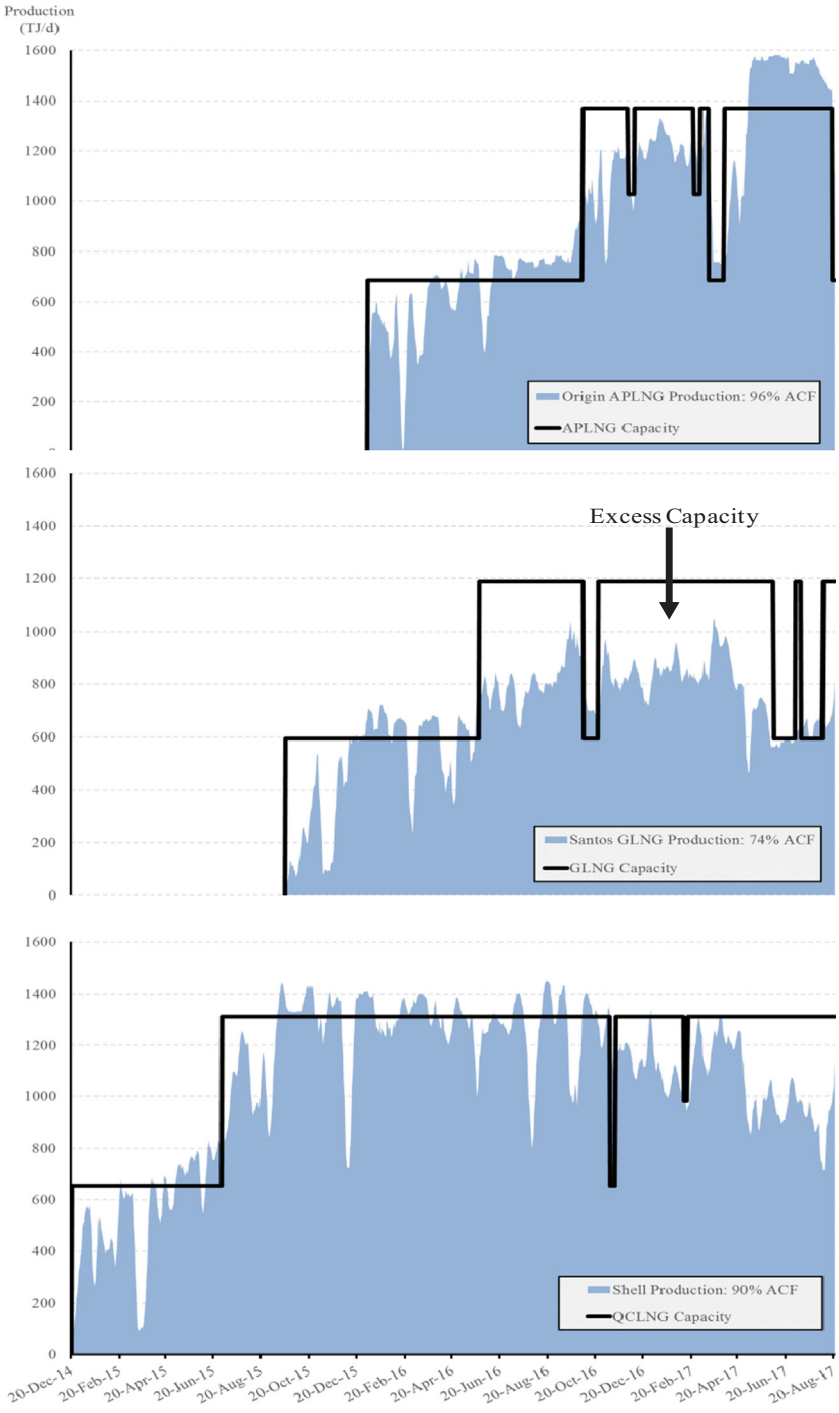

Fig. 9. LNG plant capacity vs production.
Energy Edge GMAT

During the development phase (i.e. 2008–2012) it was widely expected that rationalisation and co-optimisation of the three competing LNG projects would occur. East coast gas reserves were adequate for two terminals (4 × 250 PJ/a). A 5th LNG train would stretch the supply side (Simshauser and Nelson, 2015a). The commitment of all six trains would represent a pure *excess entry result*. Nonetheless, all the three

While each of the three LNG proposals would have had varying impacts on the domestic gas market, at least one of the projects committed was chronically undersupplied with feedstock at Financial Close, viz. one of the six LNG trains was contingent on so-called "3rd party gas". This was significant; to operate the 6th train, domestic market gas supply would be re-directed to LNG export plant. And as Fig. 9

illustrates, LNG plant has been running well below nameplate capacity, and capital markets are well aware of these conditions.

As Garnaut (2014) explains, introducing LNG capacity meant domestic users would compete with international markets and therefore pay export parity prices. This was the accepted theory. But in reality, excess LNG capacity meant Australian domestic gas prices would rise above export parity prices because of an internal supply-demand imbalance (Garnaut, 2014; Nelson, 2015; Simshauser and Nelson, 2015b). Such an outcome is *not* an error of government planning or government approvals per se. Australia is not a centrally planned economy; ultimately, critical investment error by gas producers manufactured the overhang of LNG capacity as Fig. 9 illustrated. That excess capacity now operates like a *"Hoover"* with domestic gas consumers not only needing to match export-parity market prices (i.e. long run LNG netback price), but exceed them and meet a short run 'scarcity' price (i.e. short run LNG netback price[22]). This has occurred ever since the 5th and 6th trains were commissioned (see Fig. 10 shaded area and x-axis annotations). Compounding matters were policy decisions to limit gas exploration, initially in NSW and later spreading to two other States. In consequence, just as it became visible that the demand-side would overshoot, the supply-side faced binding constraints.

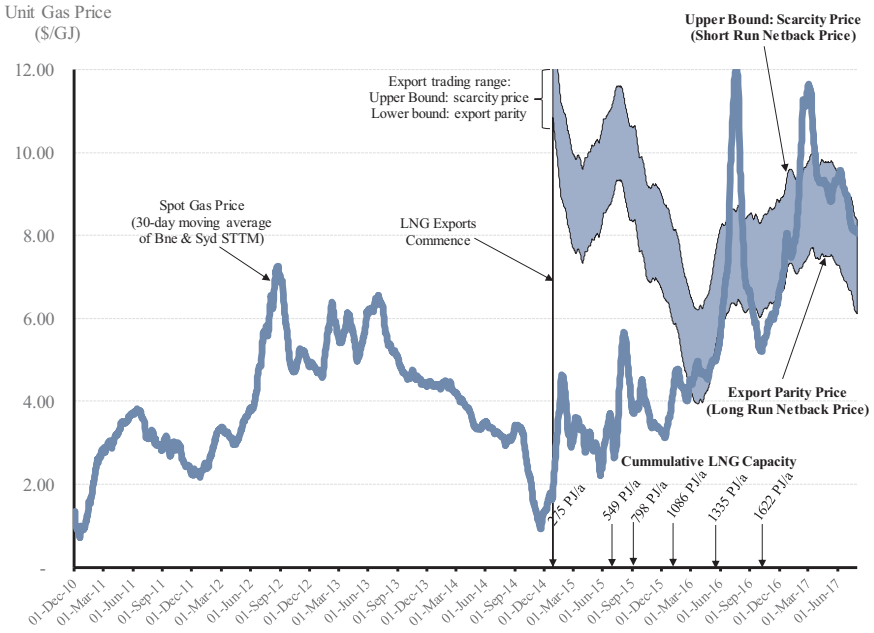

Fig. 10. Natural gas prices (Summer 2010-Winter 2017).
Energy Edge GMAT

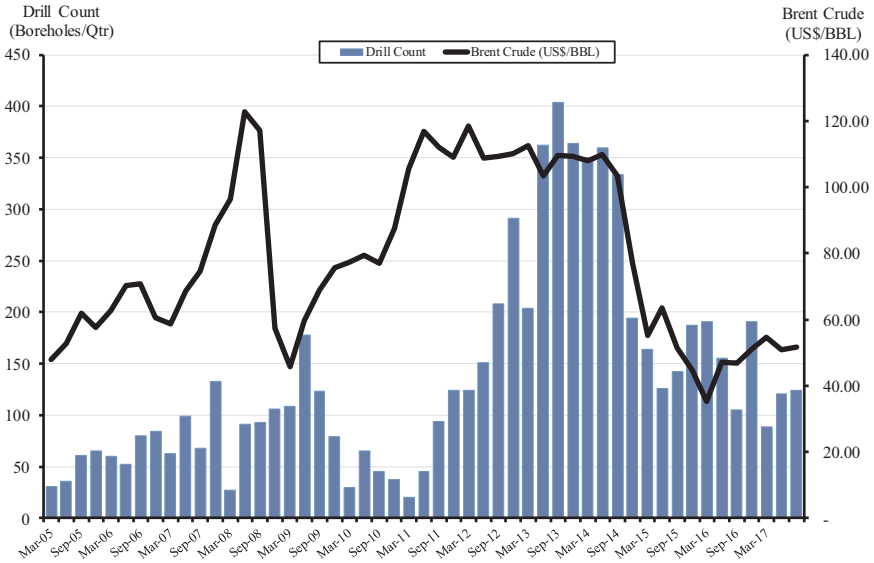

Fig. 11. East Australian drill count.
EnergyEdge GMAT.

The result is that excess LNG capacity and the 6th LNG train in particular has created an enduring scarcity pricing event in the gas market. Spot gas prices have risen to the top-end of the credible export-

[22] See Simshauser and Nelson (2015a) and Section 4.6 in particular for the equations and a discussion on the difference between short-run and long-run netback prices.

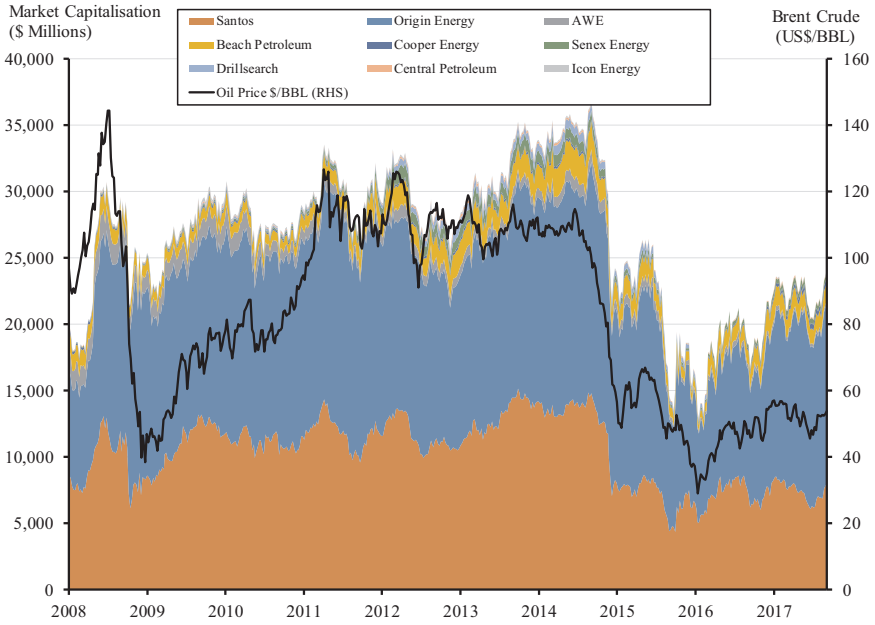

Fig. 12. Market capitalisation ASX-listed east coast oil & gas producers.
JP Morgan.

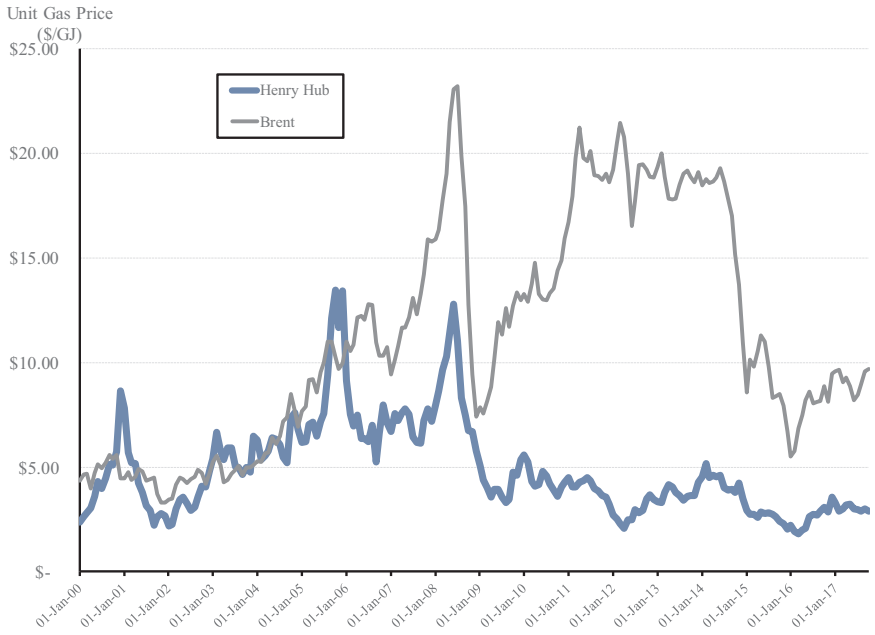

Fig. 13. Brent Crude vs. Henry Hub 2000–2017.

parity trading range with sporadic excursions above this (see Fig. 10). And ironically, in spite of elevated domestic gas prices, the lead indicator of supply expansion (gas exploration as measured by "drill count" illustrated in Fig. 11) provides little confidence that the supply-side is expanding at anywhere near the rate required to eliminate the internal imbalance. This paradox can be explained by low international oil prices, the state of incumbent oil and gas firm balance sheets following their diminished market capitalisation (see Fig. 12) and an ability to hoard 2 P reserves which are evidently rising in value based on Fig. 10 data. This tends to suggest scarcity pricing will persist into the future, which would meet the definition of a market failure (see also Samter et al., 2017).[23]

With scarcity pricing prevailing, credible long-term gas contracts (viz. 10-year tenor *at* fair long run cost) are unavailable. Instead the market is dominated by short-dated transactions, most recently in the $10–12 + /GJ range. Under such conditions gas-fired generation entry

[23] As Samter et al., (2017, p. 1) argue in their research: *"…What needs to stop is this nonsense argument that there is no issue with supply, it is just price. For a market to be sustained, supply needs to be available at a price that can be paid. Of course markets will balance, there is a price where that balance is just no market though…".*

is subject to critical hold-up[24] despite record spot prices in the electricity market. And as Wagner et al. (2014) explain, any policy designed to force gas generation into the market (at current gas prices) would result in small emissions reductions with a very large price tag.

The gravity of LNG investment error is difficult to understate, not least because of shareholder losses but because of the state the gas market has been left in. Wholesale gas prices are transmitting structural damage to the electricity sector (via gas-fired generator bid prices) which in turn is impacting all sectors of the economy. It is not inevitable that gas prices link to export prices. US gas prices were very tightly linked to oil prices until 2007 then decoupled completely as Fig. 13 illustrates (Peters and Hertel, 2017). Although an entire chapter of the Finkel Review was dedicated to the gas market there was no substantive discussion of these conditions, or recommendation on how to fix the internal market imbalance beyond being patient and increasing supply.

Perhaps the most sobering aspect of current gas market conditions is that current exchange rates (AUD/US0.75–0.80) and international oil prices (US$65/bbl) are favourable. A sharp run-up in oil prices or depreciation of the Australian dollar would elevate gas prices. The Brent price trace in Fig. 13 during Jan-11-Jun-14 should serve as a warning to policy advisers and policymakers.

In response to the gas market crisis, the Commonwealth Government introduced a contingent export control policy[25] in April 2017. Under the policy, if Australia's Independent Market Operator forecasts likely gas shortages over the ensuring 12 month period, LNG exports could be curtailed by regulatory fiat – particularly where an LNG producer is unable to demonstrate they are a "net supplier" to the domestic market (see GLNG, Fig. 9). While policymakers argue it has had an impressing effect on seasonally-adjusted spot gas prices (albeit not an evident one based on Fig. 11 data), it has done nothing for the liquidity or pricing of long-dated natural gas contracts on the east coast.[26] It is not credible policy because the fundamental internal supply-demand imbalance of the market has not been altered per se, it is merely a contingent policy and limited to assessing the market imbalance one year at a time. It seems that until one of the 6 LNG trains is subjected to a permanent closure event scarcity pricing will persist.

6. Conclusion and policy implications

From 2009–2015 incumbent coal, new entrant gas and VRE generation plant had been engaged in a generalised war of attrition. In the absence of a stable and united climate change policy architecture, and a Carbon Pricing policy mechanism in particular, the speed of coal plant exit became particularly hard to predict. Indeed *"barriers to coal-plant exit"* was a primary concern in the literature as recently as 2015 (see Nelson et al., 2015; Jotzo et al., 2015).

Marginal coal plants progressively exited as forward prices fell below their viable operating costs. But the final stages of this exit program happened to coincide with the start-up of LNG export terminals, and due to gas supply shortages, gas generation plant found it more profitable to withdraw and on-sell their long-term fuel supplies to the LNG players. In consequence, when two material coal plants exited, electricity prices rebounded very sharply and were exacerbated by the coincident mothballing of gas plant. In total, 18% of the coal-fired generation fleet had exited – and due to the age and state of plants could not be brought back. Conditions in the gas market produced a critical hold-up of gas-fired generation plant entry (and re-entry), and renewable plant development had been distorted by policy uncertainty. Two decades of climate change policy discontinuity, and an increasingly dysfunctional gas market had finally taken its toll on Australia's NEM. The US experienced an equivalent episode of coal-fired plant exit (i.e. also 18%) but this was matched with an enormous fleet of new entrant semi-base CCGT, wind and solar plant – underpinned by policy stability at the sub-national level.

The good news for the NEM, if there is any, is that the rate of renewable plant entry has accelerated rapidly in response to rising prices and will match US-equivalent results outlined in Section 3. Table 10 recasts Table 6 by incorporating the NEM's 4723 MW 'bubble' of wind and solar plant currently under construction following RET policy clarity in mid-2015. This will push Australia's Renewable Plant Entry Ratio from 0.9 × to 1.7 × coal plant exit, equal to the US ratio.

Table 10
Entry/exit ratio with Australian plant under construction.
Source: US EIA, ESAA, Clean Energy Regulator

	Coal fleet exit	Average exit age	Gas plant entry ratio	CCGT component	Renewables plant entry ratio
USA	18%	52 Yrs	1.9 × Coal Exit	1.4 × Coal Exit	1.7 × Coal Exit
Australia	18%	42 Yrs	1.6 × Coal Exit	0.5 × Coal Exit	0.9.x Coal Exit
Australia	- incorporating 3773 MW of Renewables under construction				**1.6.x Coal Exit**

So what can be learned from the NEM's recent experience? There would seem to be three key issues:

1. For market-based power systems like the NEM to function properly, investor knowledge, expectation and conviction must align with stated policy intent and policy settings – and evidently, an advanced understanding of complex policymaking processes. As a signatory to the Kyoto and Paris Agreements, energy utilities and investors, understandably, anticipated a conventional policy development cycle incorporating the distinct stages of policy development. What NEM participants experienced was two decades of climate change policy uncertainty and discontinuity. It would be naive for energy industry participants to believe climate change policy development will follow conventional processes in Australia. *Garbage Can Theory* provides a far better description of historical events, and more than likely, future developments. What industry participants can expect is that *policy influentials* will mobilise a suitable climate change policy architecture, and they will do so when an appropriate *focusing event* prizes open the requisite political window of opportunity. It may or may not be at the national level – state-based schemes can be just as effective as Jones (2014), Schelly (2014) and Simshauser and Tiernan (2018) explain. Indeed, the NEM states should collectively decide on the mechanism, and embed the policy in the state-based National Electricity Rules.
2. The exit of large incumbent base load generation needs to be carefully orchestrated. In the case of the NEM, the uncoordinated exit of coal plant, and the sudden mothballing of CCGT plant culminated in excess exit. Of the plant exit listed in Table 5, the 1600 MW Hazelwood exit proved to be decisive providing just 5 months' notice (and as an aside, driven as much by workplace risks associated with

[24] For a discussion on the relevant investment and banking conditions of generation plant entry, see Simshauser (2010).

[25] Known as the Australian Domestic Gas Security Mechanism or ADGSM.

[26] Samter et al., (2017, p. 2) note that *"…unfortunately for domestic buyers, by effectively only targeting GLNG volumes, and not price, the benchmark price for domestic gas will be set at the netback price on by far the highest price gas heading out of Curtis Island…"*.

high pressure vessels and a major fire in their coal mine). There is little doubt that other coal plants would have delayed exit had they known of Hazelwood's looming exit. From a policy perspective, just as the Market Operator publishes installed and available generation plant, so too should planned 'plant exit' be published, and ideally with minimum notification periods.[27] And as one Reviewer noted, Capacity Markets may well provide better continuity of supply than has been the case with the NEM's energy-only market design.

3. Given the importance and desirable attributes of natural gas as a transitional fuel, any country expanding into LNG production needs to be purposeful from a policy perspective to ensure that exports do not destabilise domestic markets, as has been the case in Australia's NEM. Investment error by oil and gas firms has produced an LNG capacity overhang, and a market in permanent state of scarcity. There is no visible end to the overhang because gas supply is constrained. Consequently, credible long-dated gas supply agreements, a necessary precondition for gas turbine plant financing, do not appear to be available.[28] Commonwealth policymakers have placed temporary constraints around exports in response but this has failed to enhance liquidity or future expected prices because it is a "one year at a time" policy. I have written elsewhere that a domestic gas reservation policy would be an unhelpful development (Simshauser and Nelson, 2015a; Simshauser and Nelson, 2015b). But this assumed that the supply-side would respond adequately to what were predictable shortages emerging in the 2017 period. Evidence from Australia's West Coast (where similar domestic gas shortages emerged in 2007–2008 following an LNG excess entry result) is that their policy of setting aside a certain percentage of gas reserves for domestic use has ultimately been successful in ensuring abundant supplies exist for domestic purposes, including power generation, at very competitive prices.

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[27] This was also a recommendation of the Finkel Review (which suggested 3 years notice). This can of course create policy issues. Directors of Companies have fiduciary duties and legal obligations (and associated personal liability) to avoid trading while insolvent. Minimum notification periods would therefore require some policy mechanism to deal with such circumstances.

[28] One would expect gas-fired generators to sign long-dated gas supply agreements ahead of such vast LNG plant commitments. However, the concentration of gas reserves (i.e. primarily held by the 3 LNG proponents) meant that such contracts were difficult to negotiate by the time the LNG plants were announced. Furthermore, amongst the incumbent CCGT and OCGT plants that had signed long-dated gas supply agreements ahead of LNG commitments being publicly announced, many found it more profitable to on-sell their fuel supplies to (chronically short) LNG export terminals, and then revert to spot fuel prices, reduce operating duties or indeed as Fig. 7 highlighted, mothball their plant.

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